Dominion Energy CRA Charles River Associates

DESC IRP Stakeholder Advisory Group Planning Meeting

April 12, 2021

Meeting Participants

- DESC
  - Betty Best
  - Eric Bell
  - Glenn Kelly
  - John Raftery
  - Therese Griffin
  - James Nelly
  - Sheryl Shelton
  - Joseph Stricklin

- CRA
  - James McMahon
  - Patrick Augustine
  - Gary Vicinus
  - Robert Kaineg
  - Yuki Zbytovsky

- Advisory Group
  - Anna Sommer
  - Chelsea Hotaling
  - Dawn Hipp
  - Ryder Thompson
  - Anthony Sandanato
  - Indu Manogaran
  - Eddy Moore
  - Forest Bradley Wright
  - Hamilton Davis
  - Maggie Shober
  - John Sterling
  - Natasha Puling
  - Stacey Washington
  - Will Harlan
  - Bill Cummings

Agenda

I. Introductions (30 minutes)
- Welcome
- Review: Stakeholder Homework & Prioritization of Discussion Topics
- SC PSC Order No. 2020-832 2021 IRP Update Requirements
- Timing of Commission Requirements for upcoming IRPs

II. Model Selection (60 min)
- Review: Stakeholder Input, Proposed Models, and Criteria

- Explain Model Scorecard Methodology and Define Criteria on Scorecard
- Present Model Evaluation and Rankings
- *Discussion*

<15-minute break>

III. Review Modified 2020 IRP Filing (30 min)
  - Review: Act No. 62 Evaluation Factors
  - Preferred Plan Selection Criteria
  - Discussion

IV. 2021 IRP Update Scenario Modeling & Inputs (30 min)
  - Gas Price Assumptions
  - DSM Assumptions
  - CO2 Price Assumptions
  - Discussion

V. 2021 IRP Update Resource Plan Modeling & Inputs (60 min)
  - New Resource Capital Costs & Escalation Rates
  - PPA Costs and Assumptions
  - Mini-Max vs. Other Risk Metrics
  - Modeling Existing Candidate Resource Plans
  - Model Additional Low Carbon Plan
  - Discussion

<30-minute break>

VI. Retirement Analysis (20 min)
  - Review: Short-Term Action Plan
  - Status of DESC's Retirement Analysis and Transmission Impact Analysis Request

VII. Solar Winter Capacity (20 min)
  - DESC's Understanding of the 2021 IRP Update Requirements
  - Explanation of Reliability Measurement vs. Resource Compensation Rate for PV Solar Capacity

VIII. Homework for Session III and Discussion (20 min)
  - Overview of Session II Homework
  - *Discussion*

I. Introductions (30 minutes)

Welcome

Ms. Betty Best opened the meeting by thanking and welcoming the Advisory Group to the second Stakeholder Advisory Group meeting. Betty reviewed the agenda for the meeting. She explained that the meeting time was extended for session II to allow for coverage of eight different topic sections. She referenced slide 3 and clarified that the introductory section will cover a review of the previous Stakeholder homework and prioritization of discussion topics, SC PSC Order No. 2020-832, 2021 IRP Update Requirements, and timing of Commission Requirements for upcoming IRPs.

Review: Stakeholder Homework & Prioritization of Discussion Topics

Then, Ms. Best introduced Mr. Robert Kaineg to continue the presentation.

Mr. Kaineg turned to slide 4 and described the timeline. He walked through each component beginning the week of February 16th (Session I Meeting) to April 13th (Session II Meeting) to recap how the Dominion Energy South Carolina ("DESC") team and Charles River Associates ("CRA") made progress since the last session. He outlined that Stakeholder feedback was received and incorporated into the agenda and content for the Session II meeting and read through the bullets at the bottom of slide 4 which illustrated this fact.

Mr. Kaineg then read through five Advisory Group points of feedback, along with the respective DESC responses. Mr. Kaineg then highlighted that the feedback from the Advisory Group on the meeting topic sequencing was directly reflected in the Session II meeting agenda.

On slide 7, Mr. Kaineg spoke to the incorporation of Stakeholder feedback on the model matrix. He stated that CRA has added models and evaluation criteria thanks to feedback from the Advisory Group. Mr. Kaineg mentioned that the model evaluation process and subsequent discussion will be covered more in-depth in the following meeting topic section.

SC PSC Order No. 2020-832 2021 IRP Update Requirements
Timing of Commission Requirements for upcoming IRPs

Ms. Best walked through the Order requirement timeline discussed various topics associated with the IRP update requirements from the 2020 Modified IRP through the 2023 IRP. Ms. Best also walked through the 2021 DESC IRP Update requirements and the requirements that were already addressed in the Modified 2020 IRP Update (noted on Slide 10 as requirements with checkmarks). She explained that this material is meant to confirm that each of the requirements were fully addressed in the 2020 Modified IRP and will be updated in the 2021 IRP Update. Ms. Best highlighted that these aspects differentiated the 2021 IRP Update from the 2020 Modified IRP. These differences included the potential introduction of an additional lower carbon resource plan, since the Commission found that it is prudent for DESC to add at least one additional lower carbon option to either 2021 or 2022 IRP Updates.

On slide 11, the Mr. Kaineg resumed the presentation and explained the Q&A process. He directed the Advisory Group to send questions to Mr. Patrick Augustine via the chat function. Mr. Kaineg noted that each questioner will be allowed one follow-up question before they yield the floor to the next questioner. Mr. Kaineg also explained that Q&A will be responded to in writing and posted on the DESC IRP Stakeholder Group Website at the following link: https://www.DESC-IRP-Stakeholder-Group.com.

II. Model Selection

Review: Stakeholder Input, Proposed Models, and Criteria

Mr. Kaineg first outlined the Stakeholder feedback process. This process included Stakeholder feedback on model selection criteria and suggestions for additional models and 45-minute calls with Stakeholders who offered input. He noted that no Stakeholder responded that PLEXOS was incapable of functions required by the Commission. However, there were questions raised about PLEXOS's transparency and whether the project-based license offered by Energy Exemplar would meet the intervenor needs.

Mr. Kaineg then reviewed the specific feedback that came out of the Stakeholder responses. Mr. Kaineg listed the additional models suggested for review as potential replacements for PLEXOS. He also reviewed the additional evaluation aspects that Stakeholders deemed as important. Mr. Kaineg noted that the feedback of criteria of model selection were broken out into two categories: functionality and capabilities, and transparency and licensing.

Explain Model Scorecard Methodology and Define Criteria on Scorecard

Mr. Kaineg then descried how CRA evaluated the models against two "scorecards": commission criteria and the Stakeholder criteria. He explained that the commission criteria reflect those described by the Commission in the December 23rd Order, which were considered "need-to-have" criteria. On the other hand, Stakeholder criteria were considered as "nice-to-haves" and were used to distinguish between models that score similarly on the Commission criteria.

Mr. Kaineg then reviewed each of these criteria in greater detail to expand on how CRA thought of defining them, and what could make some models perform better than others. He explained that the criteria on slides 19 and 20 call back to the same set of criteria on slide 18 but consolidated into a single definition to get a sense of what was being covered in each of the categories. Following this explanation, Mr. Kaineg read through each of the criteria, a definition of the minimum requirements, and perspective on additional functionalities.

Mr. Kaineg then provided a definition of the Stakeholder criteria and alignment to commission criteria. He then explained that there were other suggested criteria that did not overlap well with what the Commission required. Therefore, CRA evaluated these separately for all the candidate models.

Mr. Kaineg then opened the floor to accept questions.

Mr. Patrick Augustine open the floor to comments and announced that based on feedback in the WebEx chat from Stakeholders, the Advisory Group will now be able to either ask questions directly to Mr. Augustine or to the entire group. This change was made to increase transparency between Stakeholders and the DESC IRP team. All questions and answers from this session are documented in the Appendix Table 1: Questions 1 through 3.

Explain analysis approach and methodology.

Mr. Kaineg then described CRA's approach to model evaluation, noting that replacing PLEXOS is possible but would be disruptive. He explained that any replacement for PLEXOS chosen by DESC needs to perform the same key functions as PLEXOS, which include capacity expansion and portfolio optimization, as well as portfolio dispatch and risk analysis, and also should not require DESC to interpolate any cost data for analysis. Mr. Kaineg explained that the model evaluation did not try to determine which model is the "best", but which models are capable of meeting the criteria and how they compare to one another along the categories defined in the process. To justify switching away, he proposed that PLEXOS must have a shortcoming or be incapable of meeting key model criteria *and* the alternative must perform materially better in the category, while also meeting all other requirements.

Mr. Kaineg then expanded on how DESC plans to use PLEXOS for Capacity Expansion & Portfolio Optimization and Portfolio Dispatch & Risk Analysis. He described that PLEXOS includes a number of modules that reflect different and related planning analyses, but use a common set of assumptions.

Mr. Kaineg then displayed the screening process used to shortlist candidate models for further consideration. Mr. Kaineg explained that the evaluation process began with 16 different models that were subjected to the following high-level screening criteria: (1) that the model is commercial available, (2) performs both capacity expansion and portfolio analysis functions as a single package, and (3) is able to meet the functional requirements laid out by the Commission. Mr. Kaineg explained that after these three screens, four candidate models were left for further consideration: AURORA, PowerSIMM, EnCompass, and E7.

Mr. Kaineg then explained the more detailed phase of evaluation, which reviewed all candidate models against the criteria described by the Commission and provided by Stakeholders as part of the Session I feedback. On slides 30 through 34 Mr. Kaineg provided a high level overview of each of the candidate models (PLEXOS, AURORA, ABB E7, EnCompass, and PowerSIMM), and described how they differed from one another.

Present Model Evaluation and Rankings

Following the descriptions of each model, Mr. Kaineg showed the "Commission" scorecard with each of the 5 models assessed across the Commission Criteria. Mr. Kaineg walked through each of the criteria and described the differences observed between the models relative to the scorecard. Mr. Kaineg then discussed CRA's key takeaways, and he highlighted that the deeper dive into the modeling capabilities indicated no major "fails" for the candidate models, and that PLEXOS is capable of meeting all of the criteria.

Mr. Kaineg then discussed the Stakeholder scorecard. Mr. Kaineg walked through each of the criteria listed across the top row of the table and described differences between the models and how they perform against the functionalities suggested by Stakeholders. Then he noted that there were no functional "fails" for PLEXOS across the suggested criteria. He then went on to discuss the transparency afforded by the PLEXOS intervenor license and how this function had been applied in other IRP processes. Following that discussion, Mr. Kaineg outlined example uses of Energy Exemplar Intervenor Licenses from PacifiCorp and AEP, who used PLEXOS, and Idaho Power, who used AURORA.[1]

Mr. Kaineg then opened the floor to accept questions.

All questions and answers from this session are documented in the Appendix Table 1: Questions 4 through 9.

< 15 Minute Break >

III. Review Modified 2020 IRP Filing (30 min)

Review: Act No. 62 Evaluation Factors

Following the break, Mr, Kaineg briefly confirmed that slide 39 would be corrected in the posted version. After this announcement, Mr. James Neely continued the presentation to review the Modified 2020 IRP Filing.

Preferred Plan Selection Criteria

Mr. Neely described that the Commission directs DESC to consider whether the IRP appropriately balances seven key factors: resource adequacy, compliance, cost, reliability, commodity price risk, diversity of resource supply, and other. More detail on each factor was provided on slide 45. Additionally, the Order required the evaluation of plans against all scenarios, use of a cost range metric, and the evaluation of Mini-Max regret scores.

[1] This slide has been corrected in response to Stakeholder feedback. The original erroneously indicated that Idaho Power had used PLEXOS for the 2019 IRP.

On slide 45, Mr. Neely showcased a table organizing the DESC metrics used in the 2020 IRP to the factors defined by Act No. 62 and described the methods for addressing each criterion. On slides 46-49, Mr. Neely talked through the definitions of each of the DESC metrics discussed on slide 45 and how it related back to the order requirements.

Mr. Neely then opened the floor to accept questions.

All questions and answers from this session are documented in the Appendix Table 1: Questions 10 through 19.

IV. 2021 IRP Update Scenario Modeling & Inputs (30 min)

Mr. Eric Bell continued the presentation starting from slide 52. Mr. Bell explained that the DSM assumptions for the 2021 Modified IRP were going to be the same as the 2020 Modified IRP, achieving 1% savings in retail sales in years 2022, 2023, and 2024. Additionally, he explained that DESC will use the CO2 price assumptions from the 2020 modified IRP and update the natural gas price assumptions to reflect the 2021 version of EIA's Annual Energy Outlook.

Mr. Bell then opened the floor to accept questions.

All questions and answers from this session are documented in the Appendix Table 1: Questions 20 and 21.

V. 2021 IRP Update Resource Plan Modeling & Inputs (60 min)

Mr. Bell turned to slide 55 and described the DESC 2021 IRP Update resource plan modeling inputs. He discussed each of the key topics and how inputs to the 2021 IRP Update will match to what the order requires. He added that DESC is considering adding a "lower carbon" resource plan in 2021 in addition to all plans included in the 2020 Modified IRP.

Mr. Bell then opened the floor to accept questions.

All questions and answers from this session are documented in the Appendix Table 1: Questions 22 and 23.

Mini-Max vs. Other Risk Metrics

Mr. Gary Vicinus continued the presentation on slide 56 to explain the Mini-Max metric that is required by the order and how it is calculated. He described the matrix on the slide, which showcased how the Mini-Max metric would be calculated over the three investment portfolios against the four different scenarios. Mr. Vicinus explained that to calculate a regret score for each investment option across all scenarios, the user compares the outcome in the test portfolio against the lowest cost portfolio across each modeled scenario. Mr. Vicinus then explained that the Mini-Max measures the maximum of each portfolio's regret scores across all scenarios. Mr. Vicinus highlighted the concept that this regret score was only one measure of risk and that others could be considered.

Mr. Vicinus then provided examples of alternative risk metrics used by nearby utilities. He first shared the example of the Tennessee Valley Authority's (TVA) 2019 IRP, explaining that TVA performed a stochastic analysis of risk. He then walked through Duke Energy Carolinas 2020 IRP risk metric analysis, where they utilized a sampling of scenario outcomes rather than a stochastic approach.

Mr. Vicinus then noted that the DESC approach to the 2021 IRP Update would produce a similar set of data as Duke Energy Carolina's approach to risk analysis. That is, that it relies on the use of comparing portfolio outcomes across specific scenario-based outcomes. He highlighted that this method is beneficial since it allows for observation of the worst portfolio outcomes under each scenario. Mr. Vicinus noted that the range between the best (or mean) and worst outcomes are another measure of uncertainty that can be useful for observing the risk of bad outcomes for different potential portfolios.

Mr. Vicinus also described other risk metrics outside of cost risk of NPV including reliance on purchased power or imports, or reliance on a single technology. Mr. Vicinus closed by stating that there are several measures that different utilities have used to quantity the cost risk associated with portfolios. He then sought Stakeholder input and suggestions as to whether additional risk metrics should be considered beyond Mini-Max regret.

Mr. Vicinus then opened the floor to accept questions.

All questions and answers from this session are documented in the Appendix Table 1: Questions 24 through 28.

VI. Retirement Analysis (20 min)

Review: Short-Term Action Plan

Mr. Bell continued the presentation with a review of DESC's short-term action plan, the status of the DESC's retirement analysis and transmission impact analysis request from DESC resource planning to transmission planning. Mr. Bell detailed that the short-term action plan included major coal station retirements. He also reminded Stakeholders that a letter was sent to the transmission planning team to study the transmission impacts of retiring the Wateree plant. The letter was later modified due to feedback from the Commission, which led to changes in the requested cases for study. A screenshot was displayed on the screen on slide 61, noting the reasonableness of performing a more comprehensive study of the costs and impacts of the coal plant retirement and the soliciting Stakeholder feedback on guidelines for the analysis.

Status of DESC's Retirement Analysis and Transmission Impact Analysis Request

Mr. Bell then outlined the key outputs that the transmission planning team was asked to develop as part of the transmission impact analysis. He emphasized that the retirement study would provide feedback which could be used to inform upcoming IRPs and clarified that the scenarios were not intended to be prescriptive and were not intended to authorize the construction or retirement of the plants. The study will inform DESC on the relative economics of different retirement and replacement approaches, but a more detailed retirement study would need to follow if any one case were to be selected as the preferred plan. Mr. Bell explained that the studies are expected to be lengthy and are ideally sequenced properly to ensure useful study inputs.

Mr. Bell then explained the requirement that transmission planning is performed independently of the analysis done from the generation planning team. The slide listed the seven cases requested for transmission impact analysis. Case 1 replaces all units with purchase power, Case 2 repurposes the site adding battery storage and PV solar along with a small CT at Bushy Park, Cases 3 through 7 evaluate replacement with a natural gas combined cycle plant at different sites owned by DESC. After explaining the differences between the cases, Mr. Bell explained that the transmission planning group would estimate the costs and system impacts of each of these replacement cases. Mr. Bell clarified that DESC would need to make a separate interconnection request if it were to take action on any of these scenarios.

Mr. Bell then opened the floor to accept questions.

All questions and answers from this session are documented in the Appendix Table 1: Questions 29 through 35.

VII. <u>Solar Winter Capacity (20 min)</u>

DESC's Understanding of the 2021 IRP Update Requirements

After addressing all questions Mr. Bell resumed the presentation on slide 66 to address solar winter capacity credit and the 2021 and 2022 IRP Update requirements. Mr. Bell explained the different issues that were related to the measurement of solar capacity value, with the goal of focusing the group on how the seasonal capacity value of new solar PV resources ought to be reflected for the IRP planning analysis.

Explanation of Reliability Measurement vs. Resource Compensation Rate for PV Solar Capacity

On slide 67 Mr. Bell addressed the values that the Commission required DESC to use and reviewed DESC's measure of summer and winter solar capacity value. Mr. Bell explained that metered data was utilized to estimate the solar ELCC values across a number of peak hours in winter and summer. Finally, he outlined the feedback DESC hopes to receive from Stakeholders regarding the estimation of seasonal solar PV ELCC value or whether other values should be used for IRP planning purposes.

Mr. Bell then opened the floor to accept questions.

All questions and answers from this session are documented in the Appendix Table 1: Questions 36 through 38.

IX. <u>Homework for Session III and Discussion (20 min)</u>

Overview of Session II Homework

After accepting comments or questions from the advisory group, Mr. Kaineg provided an overview of some of the feedback that DESC was requesting from Stakeholders including risk metrics that could be used in addition to Mini-Max analysis, coal retirement study considerations, and PV solar capacity consideration for rates and operations.

He then outlined the expected timeline leading to Session 3 of the Stakeholder Advisory Group. Mr. Kaineg noted that DESC was seeking to align the Session with the regulatory schedule and also requested Stakeholder input on additional topics for consideration as part of the upcoming meeting.

On slide 72 Mr. Kaineg displayed the list of topics and questions that DESC requests Stakeholders to address following Session 2. He explained that the CRA team would reach out with more detail regarding the expected timeline for feedback. Mr. Kaineg noted that CRA and DESC welcomed any feedback in addition to the bullet points listed on slide 72.

Mr. Kaineg then opened the floor to accept questions.

All questions and answers from this session are documented in the Appendix Table 1: Questions 39 and through 40 are addressed here.

Ending the presentation, Mr. Kaineg explained the presentation and transmission impact analysis letter would be posted shortly to the DESC Stakeholder Advisory Group website at https://www.DESC-IRP-Stakeholder-Group.com. Advisory group members can also email DESC-IRP-Group@crai.com with questions about the website or if they have content to share with the Stakeholder group.

Appendix

Table 1 – Stakeholder Advisory Group Meeting 2: Questions and Answers

	Question / Comment	From	Topic	Answer
1	Provision of the model manual is not a "nice to have." It is required on page 29 of Order No. 2020-832	Eddy Moore	Model Selection	The DESC IRP team agrees that the minimum requirement includes that Stakeholders or other intervenors have access to all the model documentation. With that understanding, the team evaluated access to the manual as part of the Commission scorecard, which was composed of “need-to-have” requirements. The team was not attempting to determine the exact threshold of what qualifies as a manual, whether that would be a collection of files or a standalone document.
2	The actual manual of the model is required to be shared by the order. Not having access to the model manual may pose barriers to using the model and for Stakeholders to effectively engage in the Stakeholder process.	Anna Sommer	Model Selection	Understood, we agree that access to the manual is important. Some models integrate the help function into the modeling software to increase ease of access and maintain version control and may not maintain a standalone manual document. DESC will confirm the terms of sharing model documentation with intervenors.
3	I think the record should show that materials were sent to Stakeholders after 7 PM on Friday before the Monday 9 AM meeting.	Eddy Moore	Advisory Group Meeting Process	Thank you for this feedback.
4	The footnote on slide 35 says that companion financial models are used for revenue requirement	Eddy Moore	Model Selection	PLEXOS has a financial model in their LT plan which models revenue requirements. It also has financial models. In the past, DESC created spreadsheet

	modeling. Has Dominion chosen a specific financial model?			models to create total cost models outside of the modeling software, but this will be less necessary while using PLEXOS. There will still be some aspects that DESC will have to model in external spreadsheets to accurately reflect the way that the Commission requires revenue requirement reporting.
5	Typically, I think of "support" as the ability to ask questions of the vendor if we encounter an issue executing runs, e.g. the model isn't interpreting cost inputs in the way you intend. Is that kind of support available through Energy Exemplar for PLEXOS?	Anna Sommer	Model Selection	Yes. PLEXOS has a support email that is used by DESC to address the types of issues that you describe in a timely manner.
6	Based on the slides to come I don't imagine this model rises near the top, but I just wanted to mention that I don't think PowerSIMM meets the Commission's long-term cost accounting and third-party license requirements. PowerSIMM doesn't report system cost in any form (revenue requirements, NPV, annual system cost, etc.). And its "dashboard" license is a read-only license that doesn't allow the user to change inputs or rerun the model.	Anna Sommer	Model Selection	Thank you for this feedback.
7	Slides 39-40 provide an overview of how PLEXOS is used in other IRP processes. Do you have similar information for the other four models?	John Sterling	Model Selection	Our analysis approach focused on assessing the functionality of other options and whether PLEXOS met certain criteria. We did not perform the same review of intervenor use for the other models were assessed.
8	SWEPCO created a Stakeholder working group that can develop and create a limited number of	John Sterling	Model Selection	The team’s first aim is to reach a consensus on the model that will be used. We intend to be responsive

	sensitivities or cases. Then, the utility ran it on their behalf. Would DESC be willing to do that?			to Stakeholder feedback but how the model will be used is a discussion for future Stakeholder meetings.
9	A few concerns were raised pertaining to the examples provided on how PLEXOS was used in other IRP processes, which are listed below: 1. Exhibit A says that the license may only be used "for the purpose of reviewing or analyzing the electric price or power cost forecasts developed by the Client." That would *exclude its* use for IRP purposes. 2. Section 8 and the "Base Fees" section of Exhibit A say that no training or support are covered except as specified in Exhibit A. And Exhibit A says a fee of $2500 per day is required. That seems inconsistent with the provision of unlimited support and training that was encompassed in the $8000 option discussed during the IRP workshop. 3. The agreement is written as if someone other than DESC is the licensee and therefore, that someone other than DESC is paying the license fees. 4. The agreement would seem to restrict use of the license to an employee of licensee (Exhibit A), which would be problematic. A consultant to an intervenor would not be able to use it. 5. The agreement also prevents more than one employee from using the license. Consumers is providing two-seat Aurora licenses to	Anna Sommer	Model Selection	The DESC team had raised these concerns with Energy Exemplar (EE). 1. Using PLEXOS for the purpose of evaluating the IRP was discussed with EE. EE representatives confirmed that the intervenor license would allow for review of other aspects of the IRP, including portfolio analysis. 2. In discussion with EE, their team explained that the $8,000 account includes the access to the model and all the automated training modules that are on the website. The $2,500 fee is a daily charge for additional live training DESC will absorb the cost of the licensing fees; however, any additional live training fees would be the responsibility of the intervenor. 3. EE said that they would be able to accommodate an approach under which DESC paid the cost of intervenor licenses. 4. We have discussed with EE that intervenors may be using consultants' help to form their analysis, and EE explained that they would be able to accommodate this need. Both would need to sign the license agreement and confidentiality/non-disclosure.

	intervenors, so EE should do the same here or let more than one person access the license, so that we can work as a team to set up runs. 6. The agreement also states, "License granted by this Agreement shall be for the duration of the Proceeding, but in no event longer than twelve months." The current IRP has gone on for longer than twelve months from the date it was filed, this provision would potentially restrict us from using the license during the duration of the proceeding.			5. The EE intervenor license includes a single seat, but intervenors could pursue additional licenses or additional live training if they desire. 6. EE responded that they could extend licenses in the event that it was necessary to accommodate an IRP proceeding.
10	Is Commodity price risk specific to fuel costs only or are you considering broader commodity risk (steel as an example)?	John Sterling	Review Modified 2020 IRP	The Commodity price risk metric is used to evaluate the cost risk associated with fuels burned; it does not include steel. DESC assumes new generator costs, including steel prices, rise based on a Handy-Whitman index when evaluating portfolios in the IRP.
11	Have you considered tracking water intensity as a core metric?	John Sterling	Review Modified 2020 IRP	DESC does not consider the water intensity of the portfolio as a core metric but will take that suggestion into consideration.
12	Is the CO2 metric cumulative over the entire planning period or just in the year of 2049?	Maggie Shober	Review Modified 2020 IRP	The CO2 emissions metric measures the portfolio's 2049 emissions as a measure of progress towards DESC's 2050 target.
13	Are you using 2049 as a 1-year snapshot on carbon emissions? Because cumulative emissions throughout the period will cause cost risks to ratepayers if CO2 is regulated.	Eddy Moore	Review Modified 2020 IRP	The impact of cumulative emissions are captured in the CO2 costs incurred by each different portfolio. DESC will consider reporting a cumulative CO2 table into the outputs.

14	For Dispatchability and Operational Flexibility, inverter-based resources can be dispatched downward incredibly quickly and can ramp upwards just as quickly if you hold headroom. Multiple studies have been conducted as well as real-world operations of solar providing Automatic Generation Control. You should consider a class of inverter-based resources that are procured to provide dispatch flexibility rather than just must-take. Inverter-based resources are required to be capable of providing VAR support and have a broader range of reactive power that can be provided compared to fossil. Are you capturing this in your reliability criteria?	John Sterling	Review Modified 2020 IRP	DESC is aware of operational projects where solar provides Automatic Generation Control that is beneficial for other utilities. Traditionally, DESC models the resources that have been proposed and offered on the DESC system, and those proposed assets did not include solar providing AGC. DESC recognizes that part of the Stakeholder process is gaining feedback on the type of assets modeled and will consider these suggestions.
15	About reliability: where does the possibility of planned and unplanned outages fit in?	Eddy Moore	Review Modified 2020 IRP	DESC does build in planned outages to modeling, and updates forced outage rates while considering generation units. If a unit has a high forced outage rate, this value will count against the generating unit.
16	Given recent events in Texas, are potential fuel supply interruptions part of the reliability analysis?	Eddy Moore	Review Modified 2020 IRP	Yes. Our natural gas units rely on multiple pipelines from shale gas sources from the Gulf coast and several have oil fuel backup. Additionally, coal maintains a 60 to 90-day fuel supply.
17	Several DSM measures can provide some of the "reliability" criteria, e.g. Volt-VAR optimization, demand response, etc. are you accounting for the benefits that can be provided by demand-side resources?	Anna Sommer	Review Modified 2020 IRP	DESC models DR as a general program that reduces demand at a certain cost. The reliability benefits of DSM are captured in the reserve margin as DR can meet portions of the reserve margin requirements.

18	I am unaware of any other markets that measure inertia, and there is no need for this metric. As electric utility technology develops, there will be no need for this metric.	Anna Sommer	Review Modified 2020 IRP	DESC chose to include inertia in the study since the factor is still relevant to the reliable operation of the current generating system. DESC will continue to evaluate the factors and contributions to those factors by each resource type.
19	In response to comment #17: One of the people who did this webinar would be a great resource to help answer these questions - https://www.esig.energy/download/going-the-distance-moving-ac-power-from-large-inverter-based-generation-pockets-to-load-centers-nick-miller-matthew-richwine/	Anna Sommer	Review Modified 2020 IRP	Thank you for this feedback.
20	Given that there is a proposal to extend the ITC out in time, and expand it to stand-alone storage, have you considered a scenario that models those ITC changes? Few bills proposed stand-alone storage or storage getting the ITC at the same level. Grid charging no longer a detriment. Momentum and couple of bills. Timing – may see these get passed at some point this summer. Timing – could there be an upside that looked at these?	John Sterling	2021 IRP Update Scenario Modeling & Inputs	The 2021 IRP Update will utilize the same resource plans as the 2020 Modified IRP, with a potential additional low carbon plan. DESC will monitor changes to the federal ITC as appropriate in future IRP updates.
21	Will you be doing a scenario for the administration's clean energy standard of 80% by 2030 and 100% clean energy by 2035?	Maggie Shober	2021 IRP Update Scenario	DESC has not yet investigated this proposal in detail and will take the suggestion into consideration.

			Modeling & Inputs	
22	A one-for-one replacement seems to be built-in assumptions across scenarios. Given that DESC already has excess capacity and Wateree 2 is already offline for a significant period, are you considering scenarios that do not include 1 for 1 replacement of coal plants?	Will Harlan	2021 IRP Update Scenario Modeling & Inputs	DESC dos not assume a 1-for-1 replacement standard. Rather, resources are added to meet the required reserve margin in MW.
23	Does DESC consider 2022 to be a full IRP update year? Rather than an annual update?	Hamilton Davis	2021 IRP Update Scenario Modeling & Inputs	DESC understands that 2022 will be an update year and that the next full IRP will be in 2023.
24	Although I don't have a strong opinion, on which risk metric approach is preferable, but do feel strongly that stochastic analysis is often not the best way to capture risk. Prefers a scenario analysis with a range of scenario-based outcomes. I'm not a fan of the technology risk metric. This metric comes from the need to be concerned with fuel risk, but as we move away from that, it's less necessary. I believe the diversity of resources is a better metric.	Anna Sommer	2021 IRP Update Scenario Modeling & Inputs	The DESC IRP team agrees that stochastic analysis has to be properly implemented to be significant. We also agree that risk associated with some technologies are fuel related, which is a factor often considered in stochastic analysis, but some related to technology risk are often not considered. DESC's IRP analysis uses scenarios, consistent with this observation, to consider a wide range of factors.
25	Doesn't reliance on purchases also reduce the risk of being reliant on stranded assets?	Eddy Moore	2021 IRP Update Scenario	We recognize that there are potential risks and benefits of reliance on purchased power. With a greater reliance on the market comes less reliance on

			Modeling & Inputs	owned assets. Therefore, if DESC owns assets that operate below the cost of the market there can be advantages. On the other hand, if DESC owns assets that are above the costs of the market, this can strand assets.
26	Is there a liquid hub available for significant reliance on market purchases/sales?	John Sterling	2021 IRP Update Scenario Modeling & Inputs	DESC does not participate in an organized capacity or energy market, so we limit our reliance on purchases and sales and energy and capacity.
27	If approved, might SEEM change DESC's market access assumptions for energy purchases?	Hamilton Davis	2021 IRP Update Scenario Modeling & Inputs	SEEM is focused on the inter-hour 15-minute non-firm market. Therefore, it does not contribute to the reserve margin, and will not be used in reserve margin planning. It is more likely to facilitate real-time balancing and renewable integration. Implementation of SEEM could impact the cost effectiveness of different resources if they are able to sell energy into this market at favorable cost.
28	Based on our analysis of the DEC IRP, they are not actually measuring risk in a robust way. These concerns are outlined in the testimony of Kevin Lucas (CCEBA witness). So, we would not want DESC to replicate the DEC approach.	Hamilton Davis	2021 IRP Update Scenario Modeling & Inputs	The DESC IRP team thanks you for this suggestion and will investigate the materials.
29	I agree the use of scenarios can be effective to identify risks but depends on if scenarios are crafted as "likely"	Maggie Shober	2021 IRP Update Scenario	DESC agrees that it is important to consider history and potential future events that are realistic boundaries when doing scenario testing. To clarify, in

	futures or possible "extreme" futures designed to test potential resource plans. I wouldn't consider a $35 carbon fee as "extreme" since these extreme measures should truly test the system. Additionally, if there is a need to get to 80% clean energy by 2030, it would be helpful to know in advance, under the current situation, how that is possible before any regulation is created.		Modeling & Inputs	all CO2 pricing scenarios DESC also escalates the carbon fees over time. In the $35/ton scenario, for example, the CO2 price rises to over $300/ton by 2050. This may or may not constitute an "extreme" scenario but has significant impacts on the system. Thank you for your comment regarding the 2030 target.
30	For cost implications, will a securitization option be considered as part of any sensitivity analysis included in these studies?	Hamilton Davis	Retirement Analysis	Securitization requires legislation from the General Assembly, and we don't have it in South Carolina. Without legislation, securitization is not an available option at this time. There is no enabling legislation giving the Commission the authority to approve or order securitization of any retired plants.
31	Why were certain retirements presented here omitted from the IRP?	Eddy Moore	Retirement Analysis	The retirements were not omitted in the IRP. RP3 considered retirement of Wateree, RP4 evaluated retirement of McMeekin and Urquhart, and retirements of both Wateree and Williams were in RP 8. DESC still needs to do a full study of the retirements to understand the full impacts of their retirements.
32	The peaking proposal does not appear to be a one-for-one replacement. It proposes an additional 85 MW. Can you explain?	Will Harlan	Retirement Analysis	The turbine replacement is a one for one replacement of like kind vital resources at the end of their useful life. The 85 MW being questioned appears to compare winter and summer ratings inappropriately.

33	Why will this retirement study take years? Last year, Dominion completed a retirement study in Virginia in a few months. Can you give a more specific timeline?	Will Harlan	Retirement Analysis	DESC aims to have the Wateree retirement study completed by the end of 2021.
34	Why is DESC already laying out the retirement order rather than allow the study to determine the order? Part of doing the analysis is to optimize the order. What criteria are you using to determine Wateree, then Williams, and then Cope? For the replacement cases on Slide 63, wouldn't the use of a capacity expansion model provide a more robust set of replacement options for retired units?	Will Harlan	Retirement Analysis	DESC decided on the retirement order according to plant characteristics. Cope is ordered last since it is the youngest, newest, most reliable, and has dual fuel capability with gas. Wateree has lowest capacity factor and lowest site cost. Finally, due to its location on the transmission system, outages at Williams result in the most operational difficulty meaning it may be more complicated to replace.
35	For the CT replacement plan, I'd like to flag Section V of the Sercy direct testimony from the IRP proceeding. That testimony details the type of analysis CCEBA recommends for inclusion in future IRPs for evaluating system flexibility and potential improvements.	Hamilton Davis	Retirement Analysis	Thank you for this feedback.
36	Help me understand how replacement assumptions their impact analysis on front end? Would it be better to deploy this at this stage?	Hamilton Davis	Retirement Analysis	Due to required process for evaluating transmission impacts, we have to describe exactly what changes to the system we want the transmission group to study. We have added the request letter to the Stakeholder Website for your review.

37	Hamilton Davis: Refers to E3 study completed for the Duke IRP 2019-224/225E. useful for how questions on solar credit can be addressed.	Hamilton Davis		Thank you for this feedback.
38	Notes volatility in load year-to-year, mentioning that the magnitude of the peak is highly volatile. What method is used to try and assign a capacity value due to volatility in load? Could we get more detail on ELCC methodology?	Anna Sommer	Solar Winter Capacity	In DESC's service territory, the greatest firm load potential is in the winter and so this is when we forecast peaks to be highest. Previously in the 2020 IRP, DESC evaluated a number of different peak hours and the respective contribution of resources on the system during those peaks. The Commission rejected this method and mandated the ELCC at 4.25% of nameplate capacity. See Appendix F of the 2020 Modified IRP for descriptions and calculation of the ELCC used.
39	Is there a written description of the current method somewhere that goes into more detail than these slides?	Maggie Shober		As mentioned in the response to question No. 36, we have added the transmission impact analysis request letter to the Stakeholder Website.
40	For future scheduling purposes and meeting start times, can DESC accommodate folks that are participating from the western time zones?	Hamilton Davis	Meeting Process	The DESC IRP team thanks you for this suggestion and will take the change into consideration.